AMENDMENTS TO THE CLAIMS

Listing of claims:

1. (Currently Amended) A method for reducing fluid loss from a wellbore servicing fluid, comprising: combining a terpolymer with the wellbore servicing fluid to reduce the fluid loss from the fluid, the terpolymer being formed from the following monomers:

(a) from greater than ~~80%~~ 85% to about 95% of 2-acrylamido-2-methylpropanesulfonic acid or an alkali salt thereof;

(b) from about 3% to less than 10% of N-vinyl-2-pyrrolidone; and

(c) from about 3% to less than ~~10%~~ 5% of acrylamide.

2. (Canceled)

3. (Original) The method of claim 1, further comprising displacing the wellbore servicing fluid comprising the terpolymer into a wellbore in contact with the subterranean formation.

4. (Previously presented) The method of claim 1, wherein the alkali salt of the 2-acrylamido-2-methylpropanesulfonic acid comprises sodium 2-acrylamido-2-methylpropanesulfonate.

5. (Original) The method of claim 1, wherein the wellbore servicing fluid comprises a drilling fluid, a work-over fluid, a fracturing fluid, a sweeping fluid, or combinations thereof.

6. (Original) The method of claim 1, wherein an amount of the terpolymer present in the wellbore servicing fluid is in a range of from about 0.05 wt.% to about 3.0 wt.% based on a total weight of the wellbore servicing fluid.

7. (Original) The method of claim 1, wherein an amount of the terpolymer present in the wellbore servicing fluid is in a range of from about 0.1 wt.% to 2.5 wt.% based on a total weight of the wellbore servicing fluid.

8. (Original) The method of claim 1, wherein an amount of the terpolymer present in the wellbore servicing fluid is in a range of from about 0.15 wt.% to 2.0 wt.% based on a total weight of the wellbore servicing fluid.

9. (Original) The method of claim 1, wherein the wellbore servicing fluid comprises water.

10. (Original) The method of claim 1, wherein the wellbore servicing fluid comprises an aqueous salt solution.

11. (Original) The method of claim 10, wherein the aqueous salt solution comprises NaCl, KCl, KNO_3, sea salt, Na-formate, K-formate, Cs-formate, or combinations thereof.

12. (Original) The method of claim 1, wherein the wellbore servicing fluid comprises clay.

13. (Original) The method of claim 12, wherein the clay comprises montmorillonite clay, attapulgite clay, sepiolite clay, or combinations thereof.

14. (Original) The method of claim 13, wherein the montmorillonite clay comprises bentonite.

15. (Original) The method of claim 3, wherein the wellbore has a temperature in a range of from about 50°F to about 450°F.

16. (Original) The method of claim 3, wherein the wellbore has a pressure of less than or equal to about 30,000 psi.

17. (Original) The method of claim 1, wherein the fluid loss is reduced by from about 50% to about 99% when 2.0 wt.% of the terpolymer by weight of the wellbore servicing fluid is combined with a fluid containing about 35 wt.% fresh water and about 65 wt.% K-formate brine, and wherein the terpolymer comprises about 91 wt.% Na-AMPS monomer, 5.5 wt.% NVP monomer, and 3.5 wt.% acrylamide monomer.

18. (Withdrawn) A wellbore servicing fluid comprising:

(a) a water-based fluid; and

(b) a terpolymer for reducing fluid loss from the wellbore servicing fluid, the terpolymer being formed from the following monomers:

(i) from greater than about 80 wt.% to about 95 wt.% of 2-acrylamido-2-methylpropanesulfonic acid or an alkali salt thereof;

(ii) from about 3 wt.% to less than about 10 wt.% of N-vinyl-2-pyrrolidone; and

(iii) from about 3 wt.% to less than about 10 wt.% of acrylamide.

19. (Canceled)

20. (Withdrawn) The wellbore servicing fluid of claim 18, wherein the alkali salt of the 2-acrylamido-2-methylpropanesulfonic acid comprises sodium 2-acrylamido-2-methylpropanesulfonate.

21. (Withdrawn) The wellbore servicing fluid of claim 18, wherein the water-based fluid comprises a drilling fluid, a work-over fluid, a fracturing fluid, a sweeping fluid, or combinations thereof.

22. (Withdrawn) The wellbore servicing fluid of claim 18, wherein an amount of the terpolymer present in the wellbore servicing fluid is in a range of from 0.05 wt.% to about 3.0 wt.% based on a total weight of the wellbore servicing fluid.

23. (Withdrawn) The wellbore servicing fluid of claim 18, wherein an amount of the terpolymer present in the wellbore servicing fluid is in a range of from about 0.1 wt.% to 2.5 wt.% based on a total weight of the wellbore servicing fluid.

24. (Withdrawn) The wellbore servicing fluid of claim 18, wherein an amount of the terpolymer present in the wellbore servicing fluid is in a range of from about 0.15 wt.% to 2.0 wt.% based on a total weight of the wellbore servicing fluid.

25. (Withdrawn) The wellbore servicing fluid of claim 18, wherein the water-based fluid comprises water.

26. (Withdrawn) The wellbore servicing fluid of claim 18, wherein the water-based fluid comprises an aqueous salt solution.

27. (Withdrawn) The wellbore servicing fluid of claim 26, wherein the aqueous salt solution comprises NaCl, KCl, KNO_3, sea salt, Na-formate, K-formate, CS-formate, or combinations thereof.

28. (Withdrawn) The wellbore servicing fluid of claim 18, further comprising clay.

29. (Withdrawn) The wellbore servicing fluid of claim 28, wherein the clay comprises montmorillonite clay, attapulgite clay, sepiolite clay, or combinations thereof.

30. (Withdrawn) The wellbore servicing fluid of claim 29, wherein the montmorillonite clay comprises bentonite.

31. (Withdrawn) The wellbore servicing fluid of claim 18, wherein the terpolymer comprises 91 wt.% Na-AMPS monomer, 5.5 wt.% NVP monomer, and 3.5 wt.% acrylamide, wherein an amount of the terpolymer is about 2.0 wt.% by weight of the wellbore servicing fluid, wherein the water-based fluid comprises about 35 wt.% fresh water and about 65 wt.% K-formate brine, and wherein the terpolymer is capable of reducing the fluid loss by from about 50% to about 99%.